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Transformation of a Marginal Field into a Major one - the Challenges & Success: A case study from Western Offshore Basin, India

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Summary

Subsequent to the discovery of Mumbai High field in 1974, intensified exploratory activities in Western Offshore basin, India, resulted in the discovery of D-1 field besides Bassein and Panna in 1976. The D-1 field, situated about 200 km west of Mumbai city in Deep Continental Shelf at a water depth of 85-90m, was first considered in 2001, for development with geological in-place oil of about 145 MMbbl in the southern culmination (block of well D-A-4) and oil production potential of about 13,750 bopd envisaged with installation of one wellhead platform and drilling of 6 producers and 6 water injectors.

In February 2006, the field was put on production and peak production rate of about 17,500 bopd was achieved in the year 2009. In 2007, after the drilling of an exploratory well D-B-14 (north-west of D-A-4), an integrated development plan scheme was prepared, considering in-place oil of nearly 390 MMbbl, projecting an enhanced production potential of about 36,000 bopd with addition of 14 wells to be drilled from three new wellhead platforms.

Implementation of the integrated development plan was initiated in May, 2012. During the drilling of development well D-B-D#1, from close monitoring of hydrocarbon shows, the target depth was progressively extended and considerable thickness of additional deeper pay was encountered. The discovery of new oil in well D-B-D#1 has led to accretion of in-place hydrocarbons of more than 381 MMbbl and paved the way for looking far beyond the earlier estimated oil potential. A comprehensive field development scheme based on updated geological and reservoir simulation models have been initiated, a quantum jump in production potential to about 60,000 bopd is also projected.

This paper deals with the growth story of D-1 field in stages from discovery to simultaneous exploration and development. It also discusses the future development in a strategy to achieve a three-to four-fold hike of the current production rate. The field is on the verge of transformation from a 'marginal' to a 'major' oil producing field of Western Offshore basin, India.

Keywords: DCS, marginal, producers, injectors, integrated development, Lower Pay, Middle Pay, well-head platform

Introduction

The D-1 field is located about 80 km southwest of Mumbai High field in deep continental shelf at a water depth of about 90m (Figure-1). The field was discovered in 1976 with the first exploratory well D-A-1A, drilled to a depth of 3245m. Subsequent drilling of exploratory wells confirmed the oil accumulation in Ratnagiri limestone formation in five different pay zones (Pay-I to V). The oil bearing limestone facies occur at an average depth of 2150m to 2450m. Based on the exploratory well data, in-place oil volume of 417 MMbbl (383 MMbbl in the area of well D-A-4 and 34 MMbbl in the area of well D-A-12) was estimated in five pay zones in the block of well D-A-4/12.

In 1976, the second well DCS-2(D-C-2) was drilled in the north-western part and proved to be oil bearing in Middle Miocene and Late Oligocene (Figure-2). Wells D-AA-1 to the west of D-A-1A and D-A-3 south of D-A-1A drilled in two other culminations were found dry. During 1982-84 Based on interpretation of close grid Common Depth Point (CDP) survey carried out by ONGC, exploratory locations D-A-4 in the south-eastern part and D-C-5 and D-C-6 in north-western part of the field were released for drilling. In July, 1988, the location D-A-4 drilled south-west of D-A-1, proved to be successful as all the pay zones in lower Miocene limestone, flowed oil in commercial quantities. The locations D-C-5 & D-C-6, SSE & NNW of D-C-2 flowed little oil.

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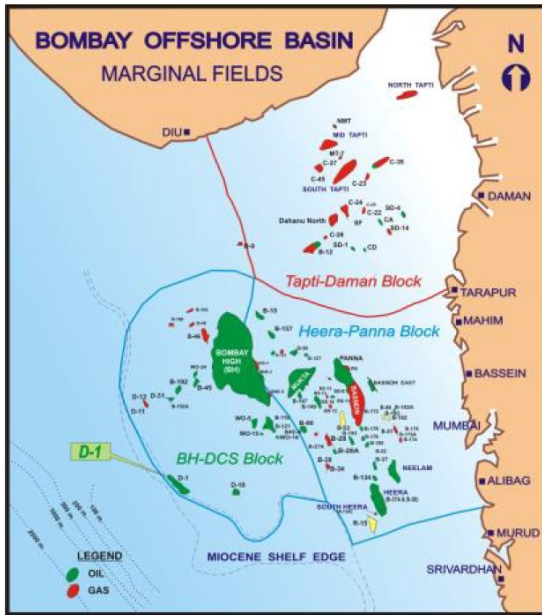


Figure-1: Location Map of D-1 Field

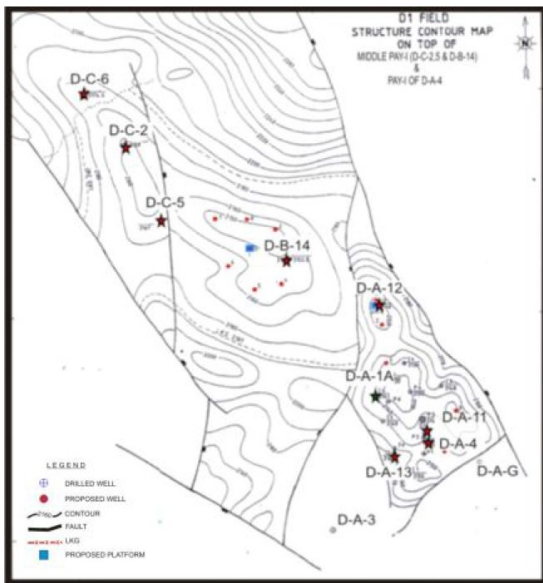


Figure-2: Exploratory wells drilled in D-1

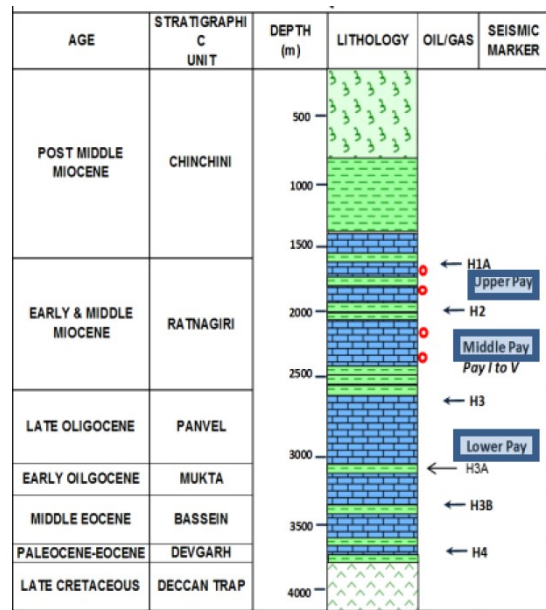


Figure-3: Generalized Stratigraphy of D-1

During 1989-90, based on the 3-D seismic data acquired, wells D-A-11 in 1991 and D-A-12 in 1992 were drilled in the southeastern part of the structure. Well D-A-13 was drilled in 1998 in the southern part with the objective to prove the continuity of reservoir facies towards the low, west of D-A-4 area and to test all prospective objects conclusively. Based on PSTM 3-D seismic data study in 2005-06, the well D-B-14 proved the presence of hydrocarbons in the area NNW of D-A-4.

The first field development feasibility study in 2001, focused on the development of the southern culmination of block of well D-A-4. The study considering Geological in-place reserves of about 145 MMbbl for development conceptualized one process-cum-wellhead platform for drilling 12 development wells (6 OP + 6 WI) in 2 phases. An integrated development plan comprising of development of D-A-12 and D-B-14 blocks and additional development of D-A-4 block was prepared in 2010 and is under implementation. Discovery of new oil thickness in development well D-B-D#1 has led to accretion of in-place oil volumes to the tune of 386.5 MMbbl, increasing the in-place oil reserves of D-1 field to nearly 985.2 MMbbl. In December 2012, the well D-A-17 was drilled to the south of D-A-4 block from one of the available slots on D-A-B well-head platform has proved the southern extension of the field.



Geological Set-up

The D-1 field is located in “Deep Continental Shelf” (DCS) block of western offshore, India. The DCS area is marked towards the west and south by a ‘paleoshelf edge’, trends NNW-SSE. The structure is a prominent NW-SE trending high along the Paleogene shelf-slope break.

The Early-Middle Miocene carbonates belonging to Ratnagiri formation constitute the main reservoir. Major accumulations are in the carbonates of Early Miocene besides some accumulations found in Middle Miocene carbonates. Generalized stratigraphy of the area is given in Figure-3. The multilayered complex carbonate reservoir, consisting of alternate porous and tight limestone layers has been found to be developed between 1650 to 2800m subsea depths (Figure-4).

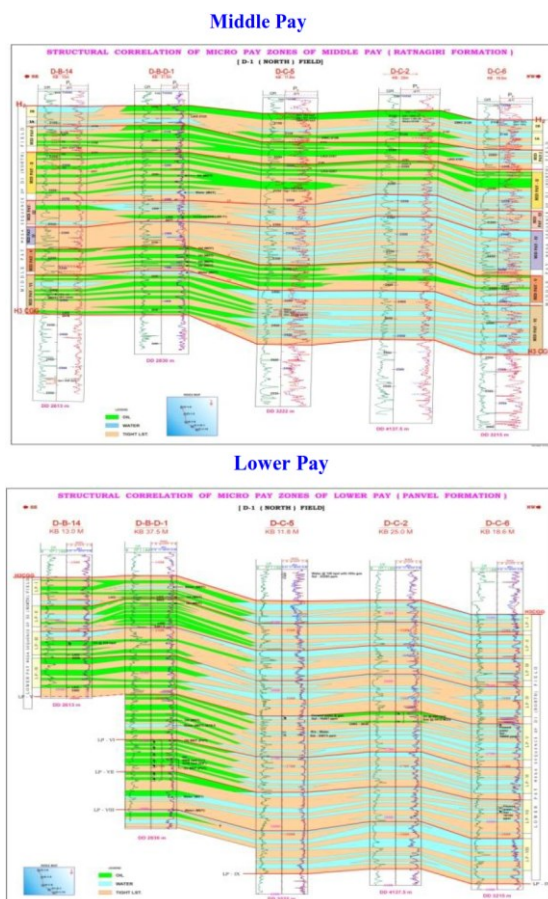


Figure-4: Geological Cross-Sections of Middle and Lower Pays

The reservoir in the D-1 field is divided into three major pays demarcated by the presence of four seismic markers, viz., H1A, H2, H3CGG and H3A. The pay between H1A and H2 marker, termed as Upper Pay (UP), belongs to Middle Miocene, the pay between H2 and H3CGG marker termed as Middle Pay (MP) belongs to Early Miocene and the one between H3CGG and H3A termed as Lower Pay (LP) belongs to Late Oligocene. The Upper and Middle pays belong to Ratnagiri Formation whereas the Lower Pay belongs to Panvel Formation.

In D-1 North area, the oil pools developed within the Early and Middle Miocene carbonates of Ratnagiri Formation have been grouped into three pays, Upper Pay (below seismic horizon H1A), Middle Pay (below H2 seismic marker) and Lower Pay. Lower pay is of limited extent found only in well D-C-2 and D-B-14. The main porosity type is of vugs, moulds and channels.

In D-1 South (Block of well D-A-4), the major accumulations are in the carbonates of Early Miocene age which are nearly 200m thick. The top of this section is marked with seismic reflector H2. Several oil bearing layers separated by tight argillaceous limestone layers constitute the pay zones. These layers are named Pay-I to Pay-V from top to bottom.

Initial Development Scheme

For development of the field, the first development scheme prepared in 2001, pertained to development of D-1 south block of well D-A-4 only with focus on main pay zones Pay-II and Pay-IV of Middle Pay (Figure-5). The in-place oil volume of about 145 MMbbl was considered in the model for development. In view of inherent uncertainties in exploitation of new structures with limited data, phased development (3 producers + 3 injectors in Phase-I and another set of 3 producers + 3 injectors in Phase-II) was recommended. Peak oil production @ 13,760 bopd with peak water injection of about 14,250 bwpd was envisaged on completion of Phase-II. ESP was planned to be installed in all the producers from the beginning due to low Gas-Oil-Ratio (GOR) character of the reservoir fluid. Cumulative oil production of 35 MMbbl was envisaged in 10 years amounting to recovery of about 24% of initial-oil in-place.

Phase-I development was commenced in December, 2005 and the field was put on production in February, 2006. In



view of the better-than-envisaged performance of the wells and good reservoir properties, the Phase-II was advanced from 2009-10 to 2008-09. Also reservoir simulation studies based on the new geo-cellular model prepared using subsurface data acquired was updated and development plan was optimized. The injection pattern was modified and the number of assigned injectors was reduced from six to three. After completion of Phase-II, the field achieved the peak oil production of about 17,500 bopd in the year 2009 (Figure-6). Against the plan of ESP in all the producers, so far, ESP has been installed in only three wells as other wells are still on self-flow.

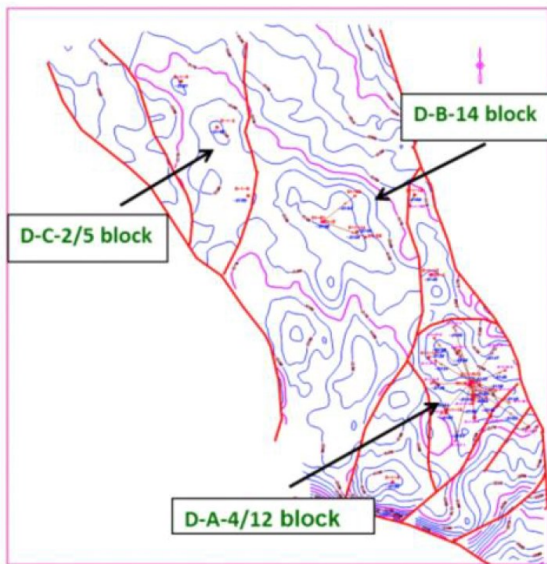


Figure-5: Structural Configuration of D-1 Field

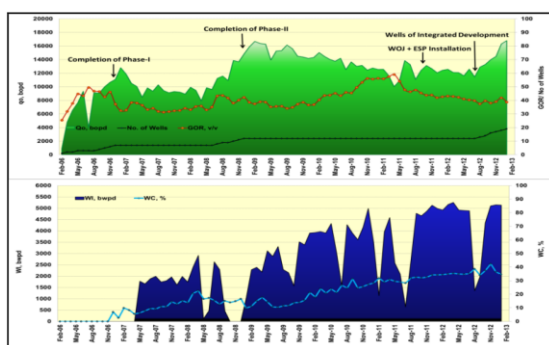


Figure-6: Production Performance of D-1 Field

The reservoir of D-1 field being a multilayered complex reservoir, attention has been given for effective reservoir management. Special PLT campaigns have been

conducted for identifying fluid flow profiles across different pays and sub-pays. Based on the detailed analysis of the PLT studies, high water producing zones were identified and remedial actions such as water shut-off jobs have been carried out to control the water production. Non-contributing zones have been identified and re-perforated. Additional perforations have been carried out to add to production. For assessing the pay-wise prevailing reservoir pressures, selective inflow performance (SIP) analysis has been carried out.

As per the initial development scheme, water injection@14,250 bwpd was envisaged through six water injectors. However, based on the reservoir performance analysis and reservoir simulation studies carried out on the new geo-cellular model, the number of injectors has been revised from six to two and water injection requirement was reduced to 10,000 bwpd which has been further revised to 5,000 bwpd considering slower rate of reservoir pressure decline.

Integrated Development Scheme

Based on the drilling results of well D-B-14 in the northern part of Central Block in D-1 field, about 131 MMbbl in-place oil volume was accreted in Middle Pay-I & II and in Lower Pay. An integrated development plan was prepared in 2010, to monetize the hydrocarbon resources in the newly explored block of well D-B-14 along with the earlier explored area of well D-A-12. The scheme considers an in-place oil volume of 390 MMbbl, covering blocks of well D-A-4, D-A-12 & D-B-14 and out of the total in-place about 260 MMbbl from the block of wells D-A-4/12 and remaining 131 MMbbl from the block of well D-B-14.

The scheme envisages a total of 14 new development wells and installation of three wellhead platforms, viz., D-A-B in the block of D-A-4 bridge-connected to the existing D-A-A platform, D-A-C platform in the block of D-A-12 and D-A-D platform in the block of D-B-14(Figure-7). After drilling of all the wells, peak oil rate of 36,000 bopd is expected to be achieved and cumulative oil production of 106.4 MMbbl (recovery of 27% of model in-place) was envisaged in 20 years (Figure-8). The terminal water cut likely to attain about 87%. Water injection of 10,000 bwpd is also recommended.

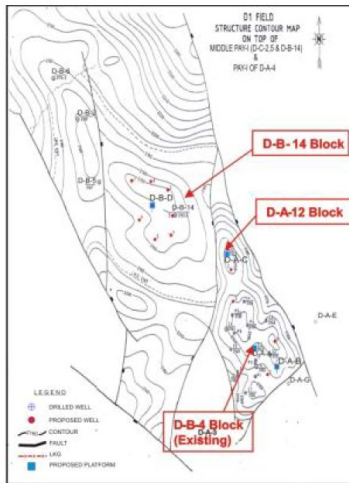


Figure-7: Integrated Development Scheme

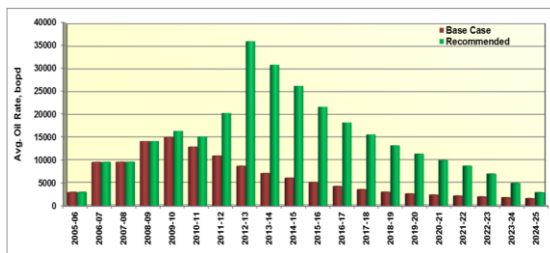


Figure-8: Envisaged Oil Production after Integrated Development Plan

Implementation of the integrated plan has been delayed by around one year because of delay in installation of D-A-B platform due to seabed integrity problem encountered at the originally planned location. Since the same barge was planned to be used for installation of D-A-C and D-A-D platforms, subsequently, commissioning of these wellhead platforms was also delayed. The hiring of FPSO planned for processing of the produced fluids and water injection has also been delayed due to redesigning of the connected bridge and well-head platform for D-A-B, delay in finalization and award of contract, this being the first instance of hiring of an FPSO. The integrated development plan is under implementation and drilling of new wells is in progress.

Discovery of New Oil Pool in Development well D-B-D#1

The first development well D-B-D#1 drilled from D-B-D platform was initially planned with an objective to exploit oil from Middle Pay-I and II. However, considering the

upside potential of Lower Pay, this well was drilled down to 2650m in Lower Pay. While drilling through the Lower Pay, the layer in the interval 2635-2640m having hydrocarbon shows was encountered as an additional development in comparison to the exploratory well D-B-14. The depth of the well was increased from 2650m to 2662m and well logs were also recorded in this section. From the electro-logs the interval 2635-40m appeared to be oil-bearing. Hence, the target depth of the well was increased in stages to see the possibility of further interesting zones. During the course of extended drilling, hydrocarbon shows were observed at various intervals which were corroborated with the electro-log data. Considering the development of additional layers of interest, the target depth of the well was further extended. During further drilling, hydrocarbon shows were observed down to 2780m. The drilling was terminated at 2830m.

In view of the hydrocarbon shows observed during drilling and encouraging log signatures, extensive data including advanced logs, viz., PEX-HRLA-HNGS Logs, XPT pressures, FMI SONIC SCANNER logs, VSP, MRX-ECS logs, MDT sampling, Sidewall Cores, etc. were acquired for confirmation of the discovery and for proper evaluation of the formation. The preliminary observation of presence of hydrocarbons during drilling was validated through Sidewall Coring and MDT sampling (Figure-9). Against the expected pay thickness of about 50m, increased pay thickness of about 225m has been encountered. The entire section of Lower Pay, below the earlier known oil column in D-B-14 block comprising of about 125m of net pay thickness has been categorized as a new oil pool.

An extensive exercise of detailed correlation of the exploratory wells with the development well D-B-D#1 has been carried out by MDT members. The geological model of the entire D-1 North Block has been revised by integrating the VSP data of wells D-B-D#1, D-B-14 and D-C-5 for horizon correlation in the 3-D PSTM seismic volume. Structure contour maps have been prepared for all the 17 sub-pays; reserves have also been estimated afresh. The discovery of new oil in well D-B-D#1 has led to accretion of in-place oil volumes in the D-1 North block of D-1 field to the tune of more than 381MMbbl, converting the status of D-1 field from a 'marginal' field to a 'major' oil field.



Challenges and the Future Development Strategy

The oil discovery in Lower pay in D-B-D#1 has opened up the way for looking below the earlier known thicknesses. After integrating the available subsurface G & G data, target depth of the planned development locations in this area has been revised to deepen up to 2850m. To monetize the newly accreted reserves, a fast-track development plan is being conceptualized considering additional drilling inputs.

The possibility of drilling additional wells from the available vacant slots on D-A-C well-head platform (3 slots) and D-B-D well-head platform (4 slots) is under examination. For better control, the exploitation of thick pay zones in the development wells is being planned through dual completion. In view of higher oil reserves, the possibility of drilling additional development wells through installation of clamp-on on D-B-D platform is also under active discussion.

Besides these, the exploratory location D-A-G drilled as an appraisal-cum-development well from the vacant slot of D-A-B platform to explore the hydrocarbon potential in the southern extension of D-A-4 block has proved to be hydrocarbon-bearing in the Middle Pay. The exploratory well D-A-15Z, located at a distance of about 3.1 km north from D-A-C platform is planned to be recompleted with subsea completion. Depending on the performance of the well D-A-17, there could be a scope of additional development in southern sector with two vacant slots available at D-A-B platform.

At present the oil production from D-1 field is being handled through EPS which was designed for handling 20,000 barrels of liquid per day. In order to handle higher volume of produced fluids and water injection, an FPSO has already been hired and commissioned in March, 2013. Depending on the potential of the new area including the western block of D-C-2, there could be a requirement of installing a new wellhead platform in the western part of D-B-14 block (Figure-10). After full-scale field development, with expected results from the wells, the production of the field can be anticipated to go up to 60,000 bopd by 2016-17 (Figure-11). The reservoir simulation study for the comprehensive development of D-1 field considering the drilling of additional new development wells is underway.

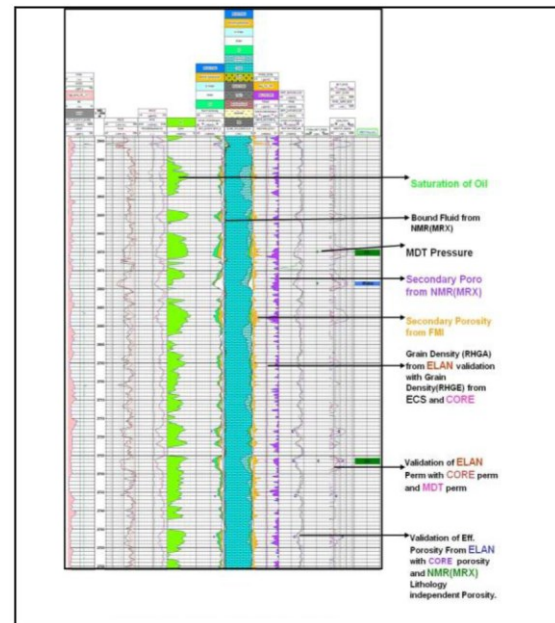


Figure-9: Well log of discovery well D-B-D#1

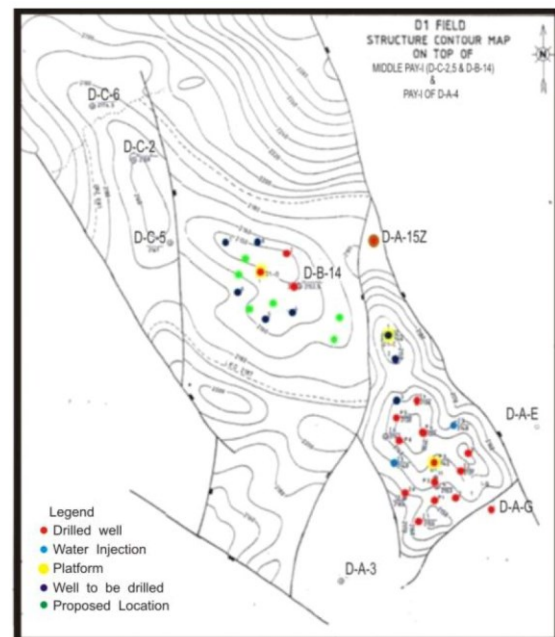


Figure-10: Future Development Locations

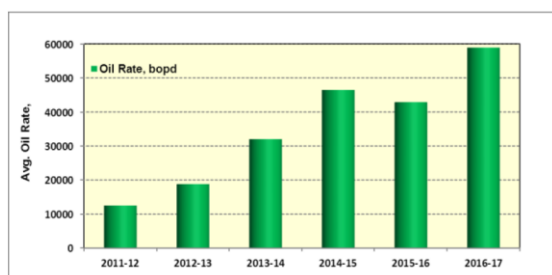


Figure-11: Likely Production Build-up

Besides, the development studies, exploration activity has been continuing in the area. Based on seismic data interpretation indicating an amplitude anomaly appearing in Mukta Formation and upper part of Bassein Formation in South D-1, the target depth of vertical development well D-A-C#1 has been increased to 3200m. Exploratory location D-A-E has been identified to establish the eastward extension of Oligo-Miocene play in D-1 field. Western and southern parts of D-C-2/5 block are also being pursued for exploration of Oligocene Play. In the north of D-1 Field, location D-31-D-A has been prioritized to explore early Eocene, Bassein, Mukta and Panvel formations as the area is interesting after hydrocarbon discovery in Bassein Formation in well DRB-1 and oil indication in Panna in well DR-1. Additionally, the north-western extension of D-1 High Trend appears to be a promising exploratory target.

The °API gravity of crude oil of D-1 field is of the order of 38 and is highly under-saturated (saturation pressure ranging from 29-63 ksc) and is of low GOR, varying from 19 to 45 v/v. The initial reservoir pressure ranges from 235 to 253 ksc from Mid Pay-I to V with reservoir temperature ranging from 132-137°C (Table-1). Integrated simulation study of D-1 south and exploitation strategy for D-B-14 area, indicate a recovery factor of 19% is likely to be achieved. In order to further enhance the recovery, some suitable Enhanced Oil Recovery (EOR) techniques are to be examined and implemented.

Table-1: Reservoir oil properties

Pay	Reservoir Pressure	Reservoir Temp.	Sat. Press.	°API	Oil FVF	Solution GOR	Oil Viscosity	Pour Point	Wax	Resin	Asphaltene
	(ksc)	(°C)	(ksc)		v/v	v/v	cp	(°C)	%Wt.	%Wt.	%Wt.
MP	235-253	132-137	29-63	39	1.2	19-45	2-3	12-15	12-15	5-7	0.4-0.77
LP	280-282	136	84-85	34	1.21	37	1.21	24	11.9	9.9	2.1

Conclusions

- The proactive and dedicated team efforts of sub-surface team members have led to major oil discovery in D-1 field through the development well D-B-D#1. Dedicated team efforts have facilitated better reservoir assessment through extensive data acquisition, optimization of well productivity, revision of geological model and reserves estimation. Concerted team efforts have also resulted in discovery of additional oil pool in the area.
- Proactive actions for preparation of comprehensive field development plan based on updated geological and reservoir simulation model have been initiated, a quantum jump in production is envisaged.
- A number of inputs have been envisaged for the development which includes drilling of additional wells from available slots of D-A-B, D-A-C and D-B-D platforms as well as installation of clamp-on slots on D-A-A Platform, development of the block of D-C-2/5 and D-B-14 by installation of an additional well platform.
- Preliminary estimates indicate peak oil production potential of about 60,000 bopd. This would promote this field to ONGC's third highest oil producing field in its western offshore operational area.

Abbreviation

- ESP: Electrical Submersible Pump
- BOPD: Barrels of Oil per Day
- BWPD: Barrels of Water per Day
- PLT: Production Logging Tool
- VSP: Vertical Seismic Profiling
- MDT: Modular Dynamic Test
- FPSO: Floating Production Storage & Offloading



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